COMMONWEALTH OF VIRGINIA

STATE CORPORATION COMMISSION

AT RICHMOND, NOVEMBER 19, 2001

COMMONWEALTH OF VIRGINIA

At the relation of the

State Corporation Commission CASE NO. PUE010306

Ex Parte: In the matter of considering requirements relating to wires charges pursuant to the Virginia Electric Utility Restructuring Act

FINAL ORDER

The State Corporation Commission ("Commission") instituted this proceeding on June 13, 2001, pursuant to our obligations under § 56-583 of the Virginia Electric Utility Restructuring Act (§ 56-577 et seq. of the Code of Virginia)("the Act"), to establish wires charges for each incumbent electric utility to be effective upon the commencement of retail customer choice in the selection of electric suppliers.

Section 56-583 A directs that wires charges shall be the excess, if any, of the incumbent electric utility's capped unbundled rates for generation over the projected market prices for generation. The projected market prices for generation as determined by the Commission shall be adjusted for any projected cost of transmission, transmission line losses, and ancillary services subject to FERC jurisdiction that the utility must incur to sell its generation and cannot otherwise recover in rates subject to state or federal jurisdiction. The Commission shall adjust wires charges not more frequently than annually and shall seek to coordinate such adjustments with any adjustments of capped rates pursuant to § 56-582.

Our June 13, 2001, Order Establishing Proceeding directed, among other things, each utility initiating retail customer choice in its service territory in 2002 to file a wires charge proposal that, at a minimum, details the issues of timing and coordination of adjustments, market price determination, and rate design issues. The order directed the Commission Staff, and permitted interested parties, to file a response to the utilities' proposals.

Wires charge proposals were filed on July 17, 2001, by Appalachian Power Company, d/b/a American Electric Power ("AEP"), Virginia Electric and Power Company, d/b/a Dominion Virginia Power ("DVP"),[1] and the Virginia electric distribution cooperatives[2] together with the Virginia, Maryland & Delaware

---

[1] DVP filed revisions to its proposal on July 27, 2001.

[2] A&N Electric Cooperative, BARC Electric Cooperative, Central Virginia Electric Cooperative, Community Electric Cooperative, Craig-Botetourt Electric Cooperative, Mecklenburg Electric Cooperative, Northern Neck Electric Cooperative, Inc., Northern Virginia Electric Cooperative, Powell Valley Electric Cooperative, Prince George Electric Cooperative, Rappahannock

Association of Electric Cooperatives (collectively, "the Cooperatives"). DVP's proposal included a wires charge rate design. AEP did not include a specific rate design proposal in its filing. AEP stated that it intended to address this in its functional separation filing, Case No. PUE010011.

The Cooperatives, which are not required to implement retail choice in their service territories until 2004, did not make a comprehensive wires charge proposal although their filing did include proposals relative to certain elements of wires charge determinations. The Cooperatives proposed the use of forward market prices of sufficiently liquid, nearby markets, and that there be a single market price for use in each cooperative's service territory. The Cooperatives also noted that their current bundled rates do not contain seasonal pricing features, but that they may, at a later date, propose establishing wires charges that vary by season.

The Cooperatives also made a proposal concerning monthly fuel adjustments through the Wholesale Power Cost Adjustment ("WPCA") clause for members of Old Dominion Electric Cooperative. In addition to having the fuel adjustment provision of the WPCA continue to be applied for bundled service on a monthly basis consistent with past practice, the

---

Electric Cooperative, Shenandoah Valley Electric Cooperative, and Southside Electric Cooperative, Inc.

Cooperatives propose that, for customers who shop for generation, the projected market price be adjusted along with monthly fuel adjustments resulting in the fuel adjustment not causing a change in the wires charge. Thus, the Cooperatives propose that there be a monthly fuel adjustment to market prices to track the Cooperatives' WPCA fuel adjustments in order to maintain a stable annual wires charge.

The Potomac Edison Company, d/b/a Allegheny Power, also made a filing on July 20, 2001, although not a wires charge proposal per se. It stated its interest in the concepts that will be developed to determine market prices in this proceeding, but noted that it will have neither a fuel factor nor a wires charge during the capped rate period of the Act.

On August 6, 2001, the Commission Staff filed a report on the utilities' proposals, and comments responding to the proposals were also filed by AES New Energy, Inc. ("New Energy"); The New Power Company ("New Power"); the Virginia Committee for Fair Utility Rates and the Old Dominion Committee for Fair Utility Rates ("Industrial Committees"); AEP; and the Cooperatives. Michel A. King of the Old Mill Power Company filed comments on the proposals on September 7, 2001.

DVP proposed using forward-looking data from EnronOnline, a wholesale electric energy trading exchange available on the Internet, for the purpose of determining market prices pursuant to § 56-583. AEP, however, asserted that the use of futures prices at this time is "premature and inappropriate" and it proposed the use of "stable and verifiable" historical prices. Because these proposals of Virginia's two largest investor owned electric utilities contained very different approaches with respect to the use of historical or forward-looking data for the determination of market prices for generation, we scheduled a hearing to receive evidence on the issue of market price determination. We directed AEP and DVP to file testimony addressing the specific recommendations contained in the Staff's August 6, 2001 Report,[3] and we permitted the parties and Staff to also file testimony or additional comments. New Energy and the Industrial Committees filed additional comments on September 7, and, as noted, Mr. King filed his initial comments at this time.

In DVP's testimony filed September 6, 2001, and AEP's testimony filed September 7, 2001, these incumbent electric

---

[3] Those recommendations were:

1) DVP’s proposed method should be seriously considered for adoption for as large a geographic portion of the Commonwealth as possible, subject to the eventual RTO structure applicable to Virginia and the caveats expressed in Section V of [the Staff] Report relating to transmission cost adjustments and base data collection time periods.

2) The Commission should further explore the bedrock issue regarding the appropriateness of the use of EnronOnline data for the purpose of projecting market prices for generation.

3) Should a market price determination method based on historical data be adopted for use in the AEP-VA service territory for 2002, the method should be the one approved by the Commission for the AEP-VA pilot in Case No. PUE980814.

utilities made significant changes to their original market price determination proposals in response to the Staff Report. DVP proposed four principal changes: (1) using Platts Energy Trader ("Platts"), a reporting service publication, as an alternative data source to EnronOnline for on-peak pricing data; (2) reducing the number of trading hubs from five (Cinergy, Commonwealth Edison, PJM West, TVA, and Southern Company) to two (Cinergy and PJM West); (3) expanding the base data collection period for forward market information from one to five days; and (4) using a different load-weighted ratio for the purpose of developing shaped prices than what was proposed in its initial filing.

DVP proposed Platts as its data source for forward on-peak prices after the Staff expressed concerns about the transparency of pricing information from EnronOnline given its proprietary nature. DVP stated that Platts is a readily accessible publication providing daily forward market "assessments" that, according to Platts, are based on market surveys of active buyers and sellers and reflect actual transactions and bids and offers. Platts characterizes its assessments as the most representative prices of the day.[4]

[4] Platts states that its assessments "take[] into consideration both transactions and bids and offers that occur after those deals are done and reflects changes in the market up to the end of the day." Exh. DFK-2, Rev. Appendix 1, at 2.

Platts publishes daily forward market assessments for six trading hubs across the country; however, those six include only two of the five trading hubs included in DVP's original EnronOnline proposal, Cinergy and PJM West. DVP therefore proposes to reduce the number of price points to these two trading hubs.[5]

Because Platts does not currently provide forward market assessments for off-peak contracts for 2002, DVP addressed concerns of liquidity and price transparency at trading hubs for off-peak contracts by using pricing data from two Internet-based electricity trading exchanges, Intercontinental Exchange ("ICE") and TradeSpark, together with EnronOnline. DVP proposed this as an interim arrangement until a news source such as Platts begins reporting forward market assessments for off-peak contracts. DVP would take the off-peak forward market bids and offers from Cinergy and PJM West from the three sources, ICE, TradeSpark, and EnronOnline; select the source with the smallest spread between the bid and offer prices; and then use the offer side of the market price quote.

Next, DVP responded to Staff's concern with the company's original proposal of using a single day's price data by now

[5] DVP stated that it would be appropriate to include any of the additional three hubs if the hub(s) were to become more active and liquid and Platts began publishing their on-peak forward price data prior to the Commission setting market prices for generation for 2002.

proposing to use five consecutive and concurrent business days, with the days selected as late in the year as possible to ensure the most accurate determination.

The final change from DVP's initial proposal was to substitute month-end and year-end load-weighted ratios for on-peak and off-peak hours, respectively, instead of using maximum load-weighted ratios, to develop load-shaped forward market prices.

DVP also addressed, in its September 6, 2001, pre-filed testimony, the Staff recommendation that the company use actual net transmission expense information obtained from DVP's on-going pilot program to develop a transmission cost adjustment to market prices pursuant to § 56-583 A of the Act. DVP had proposed a method that adjusts forward market price data by transmission costs that are expected to prevail in the Alliance RTO. DVP contends that it would be inconsistent to use a transmission adjustment based on actual historical expenses when using forward market information to determine market prices. DVP also noted that its pilot is on-going and thus the information in its transmission cost report for the pilots filed May 15, 2001, is incomplete.

AEP modified its original proposal by offering to use forward prices instead of historical prices for market price determination. It proposed using the highest bid price from among four independent exchanges (ICE, Bloomberg PowerMatch, Altra AlTrade, and TradeSpark) at a single hub, Cinergy. AEP proposed taking forward prices on the last trading day of September at 2:00 p.m. Eastern Time.

AEP stated that the use of a forward price at the Cinergy hub is the most representative of the price for which its displaced power would be sold. AEP pointed out that from among the five Midwestern trading hubs used in the market price calculation in its retail pilot, the Cinergy hub accounted for 60 percent of the market's total transactions over the period from January 28 to October 31, 2000, with the next highest accounting for only 17 percent.

AEP stated that the PJM West trading hub is not representative of the market for its displaced power because it is not directly interconnected to that hub. AEP further stated that hubs other than Cinergy have been subject to transmission constraints and congestion that have restricted sales of power from Midwest markets including AEP. AEP noted that it could not sell all of its displaced power at the highest priced hub every time because of transmission constraints.

As noted, both DVP and AEP proposed to adjust the market price for generation for transmission and ancillary service charges that assume the Alliance RTO is operational.[6] The Staff recommended that actual net transmission expense information obtained from the retail access pilot (in the case of DVP) be used to develop transmission cost adjustments to market prices. New Energy recommended that market prices be increased by transmission, ancillary, and transmission loss expenses incurred in purchasing electricity. New Energy also contended that market prices should include retail administrative costs associated with retail sales.

Mr. King proposed that no utility should be able to collect wires charges during a period for which it anticipates to make a profit on its off-system sales of displaced generation. Mr. King did not object to short-term profits being netted against short-term losses, but opposed the collection of wires charges where profits are earned over a year or more.

Certain wires charge issues related to rate design were also raised in this proceeding, although not the subject of the hearing limited to market price determination. DVP proposed as a wires charge solution to "seasonal gaming" issues that any negative wires charge "revenue"[7] that occurs from a seasonal

---

[6] AEP stated that it proposed such adjustments as part of its functional separation filing in Case No. PUE010011.

[7] Although DVP, and others in this case, including the Staff, have used the term negative wires charge "revenue," it is understood that by statute there will be no negative wires charges and, thus, no actual "revenues" will be generated from its theoretical application. In summer months, however, when

market price exceeding the embedded cost of generation in any rate element of a particular rate schedule not be netted against any positive wires charge revenue in other rate elements within the same rate schedule.[8] The Staff stated it does not object to the use of seasonal wires charges where feasible to deal with seasonal gaming issues. The Staff advocated netting any "revenues" received as a result of not having a negative wires charge against positive wires charge revenues collected in rate elements where the wires charge was positive.

New Energy shared the Staff's view in supporting seasonal wires charges, and the netting of any positive wires charges in one season with any revenues from zero wires charges in another season where they would have been negative. New Energy explained that such netting would prevent potential gaming by a utility loading up one season with high wires charges, while creating a large negative wires charge position (which by law would be zero) in another season.

---

the incumbent utilities' capped unbundled generation rate might be exceeded by the market price for generation, the actual wires charge will be zero by law, even though mathematically the wires charge would be less than zero. The issue is whether revenues from a positive wires charge in base months should be offset by the effect of what mathematically would have been a negative summer wires charge in summer months.

[8] DVP stated that it would net negative wires charges against positive wires charges for rate schedules that have a minimum stay provision. The Commission has recently promulgated regulations concerning customer minimum stay period requirements in a separate proceeding. See Case No. PUE010296, Final Order, October 9, 2001.

The Industrial Committees also supported netting what would have been a negative wires charge for one rate element against any positive wires charges occurring in the other rate elements of the same rate schedule. They stated that DVP's proposal would result in a windfall to the utility and a shopping credit to customers and competitive service providers ("CSPs") below the market price. The Industrial Committees submitted that the prohibition in the Act against negative wires charges was intended to prevent a situation in which the utility would, in effect, be paying customers to shop. They noted that this does not occur when the utility, with respect to a specific customer on a specific rate schedule and account, has different rate elements for its wires charges, some of which would be negative and some positive. In this instance, the Industrial Committees asserted, the revenue not returned to the customer when the negative rate element is zeroed out should be reflected in a lowering of the rate element for the positive wires charge.

Mr. King opposed seasonal wires charges and contended that capped rates should be restructured away from seasonally levelized rates. Mr. King also opposed not netting any revenues from negative rate elements against positive ones in establishing wires charges.

As to the issue of timing and coordination of adjustments, all parties and the Staff generally agreed that any adjustments to wires charges should be timed to coordinate with changes in fuel factor adjustments and capped generation rates, and that these changes should be in place no later than November 1 of each year to be effective for the following calendar year.[9] The parties recognized the challenge in achieving such coordination this year in view of the current status of related restructuring proceedings at the Commission.

The hearing to receive evidence on the market price determination issues was convened at the Commission on September 19, 2001. Appearances were made by counsel for the Commission's Staff, DVP, AEP, the Cooperatives, Allegheny Power, AES New Energy, The New Power Company, and the Industrial Committees. Mr. King appeared pro se. Testimony was received from Mr. David F. Koogler, Mr. Gregory J. Morgan, Dr. James R. Haltiner, and Mr. Andrew J. Evans for DVP; Mr. Bruce Braine and Ms. Laura J. Thomas for AEP; and Mr. Howard M. Spinner for the Staff.

---

[9] The Industrial Committees, however, urged that initial market prices and wires charges be set for a period longer than 12 months so as to create an incentive for customers and CSPs to contract for more than 12 months and have contracts that straddle more than one calendar year. They proposed that market prices and wires charges be set for a 20-month period.

New Energy stated that annual filings for market prices, wires charges, and fuel adjustments only 60 days prior to their effective date will render CSPs' compliance with the Commission's "class drop" provisions impossible. Our Retail Access Rules require CSPs to give 60 days notice to the Commission, the incumbent electric utility, and the customer before terminating an entire customer class of customers. New Energy recommended that we either shorten the drop notification requirements to 30 days, or extend the timing of annual filings to 75 days prior to becoming effective.

Mr. Koogler testified that DVP and AEP had entered discussions among the companies to attempt to further narrow the differences between the companies' proposals. He stated that the companies concluded that it is reasonable for the same source or sources of forward market information to be used to determine projected market prices for generation.

Mr. Braine for AEP testified that his company agrees with DVP in using the electronic exchange format for off-peak prices, but also that it prefers to use the exchanges for on-peak prices as well. He states that ICE is by far the most liquid of the exchanges and that AEP would agree to use that exchange solely rather than all four of the exchanges it initially proposed.

NOW THE COMMISSION, upon consideration of the record and the applicable statutes and rules, is of the opinion and finds that the wires charge proposals of DVP and AEP should be adopted, as modified herein, for the 2002 calendar year period.[10]

[10] On October 30, 2001, in AEP's functional separation proceeding (Case No. PUE010011), AEP, the Staff, and other parties presented to the Commission a Stipulation wherein AEP agreed not to impose a wires charge during calendar year 2002. The Stipulation did not preclude annual review and establishment of wires charges for periods after calendar year 2002, and the Stipulation stated that, except as otherwise specified, it shall not be deemed to constitute a waiver of any right or argument in any state or federal proceeding. Commission approval of this Stipulation is pending in Case No. PUE010011. Because the effect of AEP's waiver of a wires charge is limited to 2002, and the company does not waive its rights or arguments raised in other proceedings, we will decide the litigated issues in this proceeding and, absent subsequent findings to the contrary, our decisions herein will be binding on AEP at such time that it may seek to impose a wires charge. We will also direct that it perform the calculations and make the filings required by this Order. Then, should AEP seek to impose a wires charge in the future there should be no misunderstandings concerning how the calculations and determinations leading to the wires charge should be made.

We will not at this time seek to adopt by rule any particular methodology for determining market prices as many aspects of the process for determining wires charges, including the relevant markets for generation, are evolving and thus maintaining flexibility is warranted.[11]

For DVP, we will accept in part its revised proposal for determining market prices using forward price data from the Cinergy and PJM West trading hubs as reported in Platts for on-peak electricity, and, for off-peak, using pricing data from EnronOnline, and the Internet exchanges ICE and TradeSpark. However, we will also incorporate for DVP elements of AEP's proposal, namely the use of ICE for on-peak electricity prices. We believe it is appropriate to include prices from an actual exchange and the evidence demonstrates that ICE has significantly more trading volume for the relevant markets than other exchanges.[12]

Since no electric distribution cooperative has advised the Commission that it intends to implement customer choice in its service territory beginning January 1, 2002, and due to the lack of a comprehensive wires charge proposal, we do not at this time adopt a wires charge methodology for any of the Cooperatives and we will defer ruling on proposals unique to them, including the issue of monthly adjustments in market prices to correspond with fuel adjustments. Any cooperative intending to offer retail access in its service territory should submit a comprehensive, detailed wires charge proposal for review 150 days in advance of the proposed effective date for retail access.

[11] Nor will we adopt at this time the Industrial Committees' request for establishing initial market prices and wires charges for a longer period than 12 months.

[12] Tr. at 111.

All parties and the Staff now agree that it is proper to use forward-looking pricing data, and we will adopt their use at this time as the basis for establishing market prices for determining wires charges. Depending on market development, however, reversion to historic pricing figures may be needed in the future and such approach is not being foreclosed by our use of forward prices at this time.

To obtain meaningful and reliable forward pricing data at particular hubs from transparent sources it is necessary that the selected hubs be sufficiently liquid. We find it is appropriate to forego collecting prices from three of the five hubs originally proposed by DVP (Commonwealth Edison, TVA, and Southern Company) that are not reported by Platts due to their current illiquidity. The record indicates that the elimination of these three hubs from consideration should not unduly influence the ultimate determination of market prices based on Cinergy and PJM West.[13]

To arrive at on-peak base market prices for prices into Cinergy, DVP shall take the daily forward assessments from Platts, and the weighted average price/midpoint from ICE,[14] and

[13] See DVP July 17, 2001, filing, Appendix 1.

[14] We agree with the position of New Energy that a balanced approach to the issue of whether to use the bid or offer price would be to use the midpoint of the bid and offer spread. New Energy notes that many broker transactions that are consummated come close to this midpoint position. As noted, the Platts daily assessment takes into consideration both bids and offers, and

average the two prices from these sources to arrive at average market prices for Cinergy. The same procedure shall be followed to arrive at average market prices at PJM West. The higher of the two averaged prices for Cinergy and PJM West, for each contract period, shall then be used as the on-peak base market prices.[15]

We will adopt DVP's proposal for off-peak prices whereby DVP will collect data from the Internet exchanges EnronOnline, ICE, and TradeSpark, for each of the two hubs, Cinergy and PJM West. For each day from which prices are taken at the three exchanges, the exchange with the smallest spread between the bid and ask prices shall be selected for each hub, with the midpoints of such spread then used to arrive at an average price for each of the two hubs. The higher of the two averaged

---

thus it would appear to render prices consistent with the average/midpoint prices from trading exchanges such as EnronOnline, ICE, and TradeSpark.

[15] Specifically, on-peak pricing data shall be collected for a one-year forward “strip” incorporating forward contracts for the periods from December 2001 through November 2002. As discussed in this Order, infra, we will require that data be collected on 10 days. Thus, for each price point (Cinergy and PJM West) there will be 10 days of data for each forward contract period from Platts, and 10 days of data for each forward contract period from ICE. For Cinergy, the 10 daily prices from Platts for each contract period shall be averaged to arrive at an average Platts price for each of the contract periods for delivery into Cinergy. Similarly, the 10 daily prices from ICE for each contract period shall be averaged to arrive at an average ICE price for each of the contract periods for delivery into Cinergy. These Cinergy prices (for each contract period) from Platts and ICE shall then be averaged to arrive at an average Cinergy price for each on-peak contract period. Average PJM West contract prices shall be determined in the same manner using Platts and ICE. For each contract period, the higher of the average contract price for Cinergy and PJM West will then be used as the base on-peak market price for generation.

prices for Cinergy and PJM West shall then be used as the off-peak market price.[16]

AEP proposed to use forward prices from the Cinergy hub only, with both on-peak and off-peak prices obtained from an electronic exchange, using either ICE solely, or ICE with Bloomberg PowerMatch, Altra AlTrade, and TradeSpark. We will have AEP use the same data sources as DVP for on-peak prices, ICE and Platts. The evidence shows that prices posted on ICE are consistent with the assessments reported by Platts for the same hubs. Considering both pricing sources should ensure that comprehensive on-peak data is obtained.

As with data collection for on-peak prices, we will also have AEP use the same multiple data sources as DVP for off-peak pricing data, EnronOnline, ICE, and TradeSpark. The use of these three exchanges should adequately capture activity across the entire market, and by taking an averaged midpoint price from the

[16] Specifically, data shall be collected from EnronOnline, ICE, and TradeSpark, for December 2001 through November 2002, for off-peak prices at both Cinergy and PJM West. Prices shall be collected on the 10 days specified in this Order. Each day, taking the 3 bid and offer prices from each exchange for Cinergy, the exchange with the narrowest bid and offer spread shall be selected, with the midpoint of this narrowest spread determined. The 10 midpoints from whichever exchange has the narrowest spread on each of the 10 days data is collected shall then be averaged to arrive at what will be considered the forward off-peak market price for Cinergy. The off-peak market price for PJM West shall be calculated in the same manner, using the three exchanges and determining each day the exchange with the narrowest bid and offer spread, with the midpoints of the 10 narrowest bid and offer spreads from each day averaged to become the forward off-peak market price for PJM West. The higher of these Cinergy and PJM West prices shall be used as the base off-peak market price for generation.

exchange with the narrowest bid and offer spread should ensure the elimination of any upward bias in prices in the event of any "out of market" offers.

We will also require that AEP use prices at the PJM West hub in addition to Cinergy in determining both on-peak and off-peak market prices for its displaced generation. AEP shall employ the same method as we have prescribed for DVP to arrive at base market prices from the higher of Cinergy and PJM West.

AEP contends that PJM West is a less relevant market for its displaced power than is Cinergy and that to base its wires charges on market prices from the higher of these two hubs might result in AEP under-collecting for its displaced power sales.[17] The evidence shows that AEP does however, sell power to both Cinergy and PJM West, as well as at other hubs.[18] The company also has the ability to, and indeed does, make direct bilateral sales to neighboring utilities. It presumably will continue to

---

[17] AEP Witness Braine stated PJM West is physically accessible to AEP "probably less than half the time." Tr. at 155.

[18] Mr. Braine explained at the hearing that the figures in his pre-filed testimony showing 60 percent of "total transactions" at the Cinergy hub, with the next highest hub only accounting for 17 percent, apply to market transactions as a whole among 5 hubs rather than to the percentage of AEP's transactions. Tr. at 128-31. Mr. Braine testified that he does not know if AEP has studied or performed any analysis to determine precisely what percentages of its sales occur where and at what prices, but that these figures are representative of where AEP's transactions take place. He stated that Commonwealth Edison is the hub with the next highest sales and that while he did not have the exact figure, the 17 percent figure for market transactions at that hub is approximately representative of AEP's sales there. Id. at 131-34.

make such bilateral sales when a higher price can be obtained there than at one of the trading hubs through an exchange.

While it is true that AEP may not always be able to sell its power at the higher of the Cinergy and PJM West hubs, it is also true that AEP can and does sell power to other hubs[19] and through bilateral transactions. These bilateral transactions and sales through other hubs may well be at prices above either the Cinergy or PJM West prices. Presumably each such sale would be at prices higher than it could receive from Cinergy or PJM West.

Using the 60% figure for sales at Cinergy as representative of AEP's transactions, Mr. Braine acknowledged that the remaining 40% of the company's sales at other hubs (or bilateral transactions) could occur at prices higher than those obtained at the Cinergy hub.[20]

Thus, while Cinergy may account for a majority of AEP's sales, AEP does make sales for delivery at places other than Cinergy, and it does so in order to get the best price for power that it can.

---

[19] The evidence shows that the Commonwealth Edison hub ranks second behind the Cinergy hub for AEP’s sales. Because the Commonwealth Edison hub is not sufficiently liquid, it is not an appropriate price point for use in establishing market prices. However, it is still a viable alternative for AEP to sell into, and sales there will likely exceed either Cinergy or PJM West prices from time to time.

[20] Tr. at 132-34.

The use of forward-looking pricing data mandates the selection of certain trading hubs as proxies in the determination of market prices for generation. By employing Cinergy and PJM West for this purpose it is not suggested that AEP will always sell power only at the higher of these two hubs. Instead, considering both hubs should result in a more representative proxy price than looking only at Cinergy. Using Cinergy alone would not be appropriate because AEP will in fact make sales at a variety of points other than Cinergy, and we can assume that AEP would not make these sales at other points when the prices there are below prices at Cinergy.

If we permit AEP to consider only a single hub, Cinergy, where the company purportedly transacts approximately 60 percent of its sales, it will likely be over-collecting because it can, and indeed does, sell displaced power at other points. When AEP makes sales at places other than Cinergy, as it does approximately 40 percent of the time, it presumably would not have done so unless it could net a higher price for its power at those other points than it could at Cinergy. Thus, we believe that requiring AEP to use the higher price from two liquid hubs creates a proper balance, and fairly reflects what the company may expect to receive from the various options available to it for the sale of any displaced power.

On the issue of adjustments to the projected market price for generation for any projected transmission costs, as required by § 56-583 A, DVP should use actual net transmission expense information obtained from its pilot program to develop a transmission cost adjustment to market prices. We find it to be inappropriate at this time to forecast what transaction costs would prevail inasmuch as rules governing the Alliance RTO charges are evolving. DVP should use actual net transmission expense from its pilot program to develop a transmission cost adjustment. DVP shall continue to collect data on their actual expense for unitized third party sales per kWh as filed in its report of May 15, 2001, in Case No. PUE980813, and shall update this data through the latest period practicable and file it with its market price calculations as directed herein.

AEP lacks meaningful data on such transmission expenses because it has no actual experience with transmission costs incurred for displaced power in its pilot. We will require AEP to identify transmission costs, on a per kWh basis, paid to third party transmission suppliers, associated with off-system sales sourced by units that would otherwise serve Virginia jurisdictional load. It is the sale from these units that would be transmitted if AEP's Virginia customers choose a CSP under retail access. AEP shall develop proxy transmission cost data and file such on or before December 3, 2001, along with work papers that support its estimates.

For the time over which market-pricing data should be collected, we agree with New Energy that a sufficiently long period should be used to avoid any undue impact from unusually low or high prices over a few days. We find that it is appropriate to select ten days, spread over a six to eight week period, and weighted towards the most recent weeks. The following days shall be used: October 8, 16, and 24, 2001, and November 1, 9, 12, 13, 14, 15, and 16, 2001.[21]

We accept DVP's proposal for seasonal wires charges, except that we will require that any revenues that would have been returned in a particular season via the wires charge calculation for a rate element shall be considered in establishing any positive wires charges. The company will have the opportunity to be made whole. There has been no showing of harm to the company in its pilot caused by customers leaving and then returning to capped rate service.

We cannot adopt Mr. King's recommendation to restructure utilities' capped rates away from seasonally levelized rates toward rates more reflective of the expected cost of wholesale electricity on a seasonal basis. Redesigning rates would

[21] We realize that for data collected in October the full December 2001 through November 2002 12-month strip might not be available. Market prices may be calculated on the data available.

necessarily raise some rates and lower others. Section 56-582 of the Act does not permit us to do that. Rates may be adjusted only in connection with five limited situations, none of which fall within the scope of Mr. King's proposal rate adjustment proposal.

Nor can we impose Mr. King's recommendation that a utility should not be allowed to collect wires charges during a period for which it expects to make a net profit on selling its displaced energy over an appreciable period of time.[22] As with our inability to adjust base rates, we do not read the Act so as to permit disallowance of properly calculated wires charges under the circumstances Mr. King describes. Although the Act does cap the rates a utility may charge, it does not cap a utility's revenues or its profits.

New Energy proposed that market prices for generation include costs such as retail administrative costs and transmission costs that a CSP will incur in supplying electricity to retail customers. Because CSPs will incur these costs to serve its customers, such "retail adders" to market

[22] It is not clear how “profit” would be defined under Mr. King’s proposal as utilities incur both fixed and variable costs in the generation of electricity.

prices for generation would enable a true comparison of such rates with the retail generation rates of a CSP.[23]

New Energy stated that such cost adjustments are needed in order to make a fair and equitable comparison of the market price and the utility's price to compare, and that the adjustments would promote competition. We do not disagree that allowing for "headroom" by incorporating retail costs in market prices would fairly recognize the costs CSPs will incur to serve customers, and would likely promote competition. However, it would not be revenue neutral to the incumbent utility.

The Act, in our view, is designed to make the incumbent utility whole, with the wires charge priced to make the utility indifferent as to whether it recovers stranded costs through capped rates or wires charges. Including retail costs in the calculation of market prices would not likely leave the utility in a revenue neutral position as the Act is designed to do. We cannot, therefore, find that the Act authorizes such action. If the General Assembly determines that this measure is appropriate to advance competition it, of course, may amend the Act to allow it.

[23] Alternatively, New Energy would support a wholesale pricing comparison where an incumbent utility’s retail-related costs would be subtracted from the generation component of the utility’s rates to reflect the true wholesale cost of serving customers.

Finally, on the issue of the timing of adjustments to wires charges and their coordination with changes in fuel factors and capped generation rates, we find that going forward, utilities shall make filings by July 1 of each year for any proposed revisions in their fuel factor and corresponding changes in capped rates, along with market price proposals, so that market prices and wires charges can be determined by the Commission by October 1 for the following calendar year.

We recognize that the timing of restructuring proceedings at the Commission in this initial year of phasing in full retail access will present challenges for competitive suppliers in initiating their marketing efforts at the commencement of customer choice in the Commonwealth. The schedule going forward should enable CSPs to formulate and implement pricing and marketing strategies sufficiently in advance to facilities their participation in the competitive marketplace.[24]

Accordingly, IT IS ORDERED THAT:

(1) The generation market price methodologies for purposes of establishing wires charges for DVP and AEP for 2002, as revised by the companies in this proceeding, are approved as modified herein.

---

[24] The determination of market prices and wires charges 90 days prior to their effective date should also eliminate New Energy's concerns in complying with the Retail Access Rules' class drop notice requirements.

(2) DVP's wires charge rate design proposal is approved, as modified herein.

(3) To the extent not otherwise addressed herein, AEP's wires charge proposal shall be considered in its functional separation proceeding, Case No. PUE010011.

(4) On or before December 3, 2001, DVP and AEP shall file reports showing the results of their base market price calculations and authorized adjustments, with supporting data, and after load shaping for each rate class, the rate class specific market prices for generation.

(5) Incumbent electric utilities seeking to impose a wires charge in calendar year 2003 and beyond shall make annual filings by July 1 of each year for any proposed revisions in their fuel factor and corresponding changes in capped rates, and for market price proposals.

()(6) This docket shall remain open for the receipt of reports to be filed herein and for consideration of other matters concerning market price determination and wires charges, as they may arise.